Southern California Edison Company
SB 695 Report To Energy Division
Year: 2020

1. Opening Comments

In response to the Energy Division's Data Request dated January 3, 2020, SCE is providing the following information to assist the Commission in preparing its Senate Bill (SB) 695 annual report to the Governor and Legislature. Specifically, SB 695 requires:

> "that by May 1, 2010, and by May 1 of each year thereafter, the commission also report to the Governor and Legislature with its recommendations for actions that can be undertaken during the upcoming year to limit cost and rate increases, consistent with the state's energy and environmental goals, including the state's goals for reduction in emissions of greenhouse gases. The bill would require the commission to annually require electrical and gas corporations to study and report to the commission on measures that they recommend be undertaken to limit costs and rate increases."

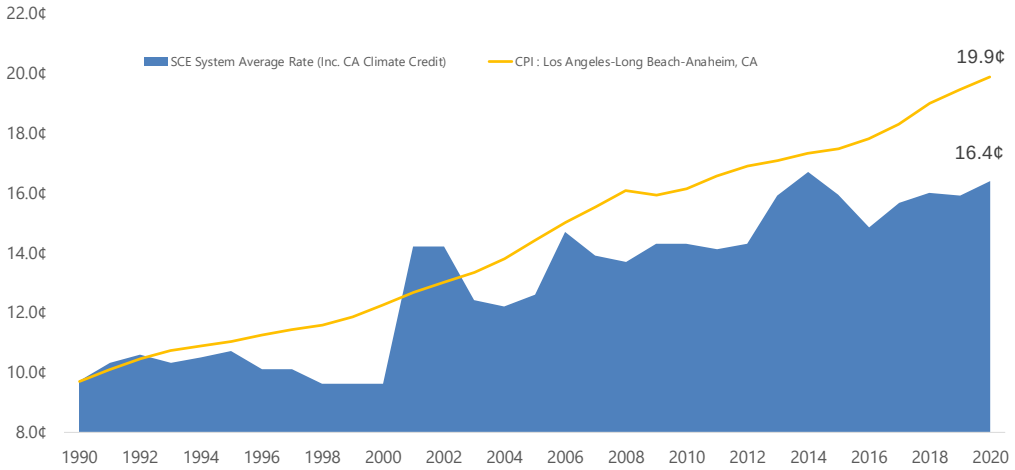
The information provided includes SCE's overall rate policy, a discussion of SCE management's policies and practices to control costs and rate increases for customers, and a discussion of SCE's policies and recommendations for limiting rate increases while meeting the State's energy and environmental goals for reducing greenhouse gases. SCE also provides a brief overview of additional programs the company is proposing in the short term to minimize wildfire risk. Appendix A to this Report describes SCE's revenue requirements and provides an outlook for pending revenue requirement and rate changes from May 1, 2020 to April 30, 2021.

2. Overall Rate Policy

SCE's overall rate policy is to fully recover its authorized revenue requirement in an equitable manner while supporting public policy objectives. SCE

designs its rates to meet the traditional design objectives (e.g., recovery of authorized revenue requirement, rates based on cost of service, and rate stability), while supporting the various public policy objectives established by the legislature and regulators. By recovering its authorized revenue requirement through cost-based rates, SCE can safely operate, maintain and invest in its distribution system, provide reliable and clean power, and meet customer service needs as they arise. Recovering these costs equitably from customers ensures that those customers who are more costly to serve pay appropriately higher rates. Rates that are equitable and cost-based also send the correct price signals to customers and prevent uneconomic decisions regarding energy usage.

Figure 1 below shows a comparison of SCE's actual System Average Rate[1] as compared to what the average rate would have been if it had changed commensurate with the Consumer Price Index.[2] SCE's system average rate is near peak levels on a nominal basis, however, on a real dollar basis, SCE's 2020 system average rate remains significantly below peak rates in the early 2000's.



[1] The System Average Rate shown includes the total annual California Climate Credit to be returned to all customers in 2020 and prior periods.

[2] Consumer Price Index for All Urban Consumers Los Angeles-Long Beach-Anaheim, CA (1982-84=100) IHS MARKIT ECONOMICS December 2019 Forecast Source: Bureau of Labor Statistics

The costs of service, which are comprised of capital and expenses associated with replacing or maintaining an additional unit, differ by rate class, and make up one of many principles underlying SCE's practice of revenue allocation and rate design. The marginal cost of service is used as the basis for revenue allocation between the rate classes, and for rate setting as the foundation of retail rates.

In revenue allocation, once the marginal costs of service and marginal cost revenue responsibility[3] have been determined by rate class, the authorized revenue requirement, or the amount of revenues to be recovered from each class for operational or program capital and expenses, is then allocated to each class based on the proportion of marginal cost revenue responsibility that is attributed to each class. Generally, the class average rate is higher than the system average rate when the rate class in question contributes to a higher proportion of costs relative to the system average and to other classes.

In revenue allocation, a collaring mechanism is used to limit total change in revenue responsibility allocated to each rate class, based on adopted marginal costs. The collaring mechanism applies a percentage change cap and floor to the amount of change a rate class can expect to see in revenue allocation from one General Rate Case cycle to the next. Although the collar mechanism obscures the direct impact of cost-based revenue allocation, the mechanism restricts the magnitude of change in revenue allocated to each rate class and consequently has the effect of stabilizing rates and providing a measure of affordability.

[3] Marginal cost revenue responsibility is determined by applying the billing determinants to rates set at the marginal costs levels for each class.

In addition to introducing a collar mechanism to moderate any changes in average class rates due to revised revenue allocation, other measures are taken to address structural deficiencies in rates to improve bill stability and affordability in certain segments. For example, beginning March of 2019, the residential baseline allowance for basic residential customers was increased from 53 percent of average usage in each climate zone to the statutory maximum 60 percent, increasing the amount of monthly usage (kWh) that qualifies for the lowest first tier rate. Additionally, per D.18-11-027, efforts are underway to increase customer enrollment in the Family Electric Rate Assistance (FERA) Program, which offers households with three or more persons living between 200 and 250 percent of the Federal poverty level an 18 percent discount off their bill.

Tables 1 and 2, shown in nominal and real values respectively, provide a view of trends in rates for SCE's different customer classes. Data through 2018 are based on billed operating revenues and sales. Data for 2019 is based on forecast revenues and sales. Table 3 provides an alternative view of this data by expressing this information as a percent of the system average rate.

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Table 1

Historical Average Rates by Rate Group (Nominal ¢/kWh) Based on Recorded Revenue and Sales
2019 Average Rates by Rate Group Based on Forecasted Revenue and Sales

Bundled Service

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020 [1]
Domestic	11.4	11.4	11.5	13.0	13.5	12.8	12.5	12.9	15.7	15.3	15.0	15.2	15.5	15.6	15.9	16.7	16.4	16.6	16.2	16.9	17.7	18.0	19.4
TOU-GS-1	12.1	12.1	12.0	16.2	17.5	15.8	14.8	15.2	17.6	17.6	17.0	16.9	17.5	17.3	17.6	17.5	18.3	18.0	15.9	16.7	17.3	17.2	17.8
TC-1	7.3	7.4	7.4	10.3	13.5	12.4	12.0	11.5	13.4	13.5	13.8	14.5	15.8	15.9	15.6	16.9	18.6	19.0	17.9	18.1	18.8	18.6	18.4
TOU-GS-2	9.9	10.2	10.1	13.2	15.5	14.1	13.3	13.5	15.6	14.3	14.3	14.8	15.7	15.4	14.9	16.2	17.4	17.3	15.9	16.8	17.2	17.0	17.6
TOU-GS-3	9.7	8.9	10.2	13.1	14.7	13.0	11.8	10.8	13.6	14.2	14.1	14.3	13.7	13.2	12.7	14.3	15.9	15.8	14.2	15.1	15.4	15.1	15.9
Sm. and Medium Comm.	10.3	10.5	10.4	13.7	15.8	14.4	13.5	13.6	15.6	14.9	14.7	15.0	15.5	15.2	14.9	16.0	17.2	17.1	15.5	16.4	16.8	16.6	17.2
TOU-8-Sec	8.1	8.2	8.7	12.2	14.3	12.6	11.2	11.3	13.2	12.5	12.4	12.7	13.1	12.7	12.3	13.7	15.0	14.9	12.7	13.7	14.0	14.0	14.2
TOU-8-Pri	7.2	7.4	7.9	10.9	13.0	11.5	10.3	10.7	12.6	11.9	11.8	11.7	11.8	11.5	10.9	12.1	13.2	13.1	11.1	12.0	12.4	12.4	12.9
TOU-8-Sub	4.9	5.1	5.7	8.3	9.4	8.4	7.4	7.5	9.1	8.3	8.1	7.9	8.0	7.6	7.0	8.1	9.1	9.1	6.5	8.0	8.3	8.4	9.2
Large Power	6.8	7.1	7.7	10.6	12.6	11.2	9.9	10.0	11.8	11.1	10.9	10.9	11.1	10.6	10.1	11.7	12.9	12.8	10.6	11.7	12.0	11.9	12.5
PA-1	12.8	12.1	12.1	14.3	15.3	14.9	14.0	15.1	18.2	16.9	17.5	17.8	19.4	19.7	18.5	12.3	14.4	13.8	13.0	14.2	14.5	14.8	14.8 [2]
PA-2	8.7	8.5	8.7	10.7	11.3	10.5	10.4	10.7	12.8	12.5	12.8	13.1	14.8	14.9	14.2								
AG-TOU	7.4	6.9	7.5	9.4	10.1	9.0	8.5	8.5	10.0	9.6	9.7	9.9	10.9	10.3	9.3	12.0	13.2	12.3	10.4	11.3	17.7	18.0	12.5 [3]
TOU-PA-5	6.9	6.3	7.0	8.8	9.4	8.2	7.8	7.8	9.4	9.0	8.9	9.1	9.9	10.3	9.1								
Ag. and Pumping	8.8	8.5	8.7	10.6	11.1	9.9	9.4	9.5	11.3	10.9	10.8	11.0	12.0	11.6	10.8	12.1	13.8	13.1	11.9	12.9	13.3	13.5	13.8
St. and Area Lighting	17.0	14.1	13.9	15.8	17.3	15.5	14.7	14.0	15.3	16.9	17.9	18.7	19.0	18.9	18.1	18.2	18.7	19.1	18.0	18.4	18.6	19.2	18.1
STANDBY/SEC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	11.2	12.7	13.3	11.7	12.5	12.8	9.7	14.0
STANDBY/PRI	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	11.9	12.5	13.0	11.1	12.2	12.5	12.5	14.1
STANDBY/SUB	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	7.9	9.3	9.5	5.9	7.9	8.0	8.6	9.1
Standby	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	9.1	10.1	10.5	7.3	9.0	9.0	9.3	10.3
Total System	9.6	9.9	10.0	12.5	14.0	12.9	12.2	12.4	14.6	14.0	13.8	14.0	14.4	14.2	14.1	15.0	15.7	15.6	14.4	15.4	15.8	15.8	16.7

[1] Forecasts calculated from Present Rate Revenues ("PRR") from 2020 ERRA Application (Nov 2019 Update). Excludes PUCRF Revenues.
[2] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands < 200 kW (PA-1 and PA-2 mapped to TOU-PA-2)
[3] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands ≥ 200 kW (AG-TOU and TOU-PA-5 mapped to TOU-PA-3)

Note: During the Enery Crisis of 2001-2002, the Commission adopted a 3 ¢/kWh surcharge. The majority of the impact of this increase went to Large Power and Commercial customers. SCE, over time, is driving towards getting each group to pay its cost to service.

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Table 2

Historical Average Rates by Rate Group (Real ¢/kWh) Based on Recorded Revenue and Sales
2019 Average Rates by Rate Group Based on Forecasted Revenue and Sales

Bundled Service

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	[1]
Domestic	17.5	17.2	16.7	18.3	18.5	17.1	16.2	15.9	18.6	17.5	16.6	17.0	17.1	16.7	16.7	17.4	16.8	17.0	16.2	16.4	16.6	16.3	17.1	
TOU-GS-1	18.6	18.1	17.5	22.7	23.9	21.1	19.1	18.7	20.9	20.2	18.9	18.8	19.3	18.6	18.6	18.2	18.8	18.3	15.9	16.3	16.2	15.6	15.7	
TC-1	11.2	11.1	10.7	14.5	18.4	16.6	15.5	14.3	15.9	15.5	15.3	16.2	17.4	17.1	16.4	17.6	19.1	19.4	17.9	17.6	17.6	16.9	16.3	
TOU-GS-2	15.3	15.4	14.6	18.6	21.2	18.8	17.2	16.7	18.4	16.4	15.9	16.6	17.4	16.5	15.7	16.9	17.9	17.6	15.9	16.4	16.1	15.4	15.5	
TOU-GS-3	14.9	13.4	14.9	18.4	20.2	17.3	15.2	13.3	16.2	16.3	15.6	15.9	15.1	14.2	13.4	15.0	16.4	16.1	14.2	14.7	14.5	13.8	14.0	
Sm. and Medium Comm.	15.8	15.8	15.1	19.3	21.7	19.2	17.5	16.8	18.4	17.1	16.3	16.8	17.1	16.3	15.7	16.7	17.7	17.4	15.5	15.9	15.7	15.1	15.2	
TOU-8-Sec	12.4	12.3	12.7	17.1	19.5	16.8	14.4	14.0	15.6	14.4	13.8	14.2	14.4	13.6	13.0	14.2	15.4	15.2	12.7	13.4	13.1	12.7	12.5	
TOU-8-Pri	11.1	11.0	11.5	15.3	17.8	15.3	13.3	13.2	14.9	13.7	13.1	13.0	13.0	12.3	11.4	12.6	13.6	13.4	11.1	11.7	11.7	11.2	11.3	
TOU-8-Sub	7.6	7.7	8.2	11.7	12.8	11.2	9.6	9.3	10.8	9.6	9.0	8.8	8.8	8.2	7.4	8.4	9.4	9.3	6.5	7.8	7.7	7.6	8.1	
Large Power	10.4	10.7	11.2	14.8	17.2	15.0	12.8	12.4	13.9	12.7	12.1	12.2	12.2	11.4	10.6	12.2	13.3	13.0	10.6	11.4	11.3	10.9	11.0	
PA-1	19.7	18.2	17.5	20.1	20.9	19.8	18.0	18.6	21.5	19.4	19.4	19.9	21.4	21.1	19.5	12.8	14.8	14.0	13.0	13.8	12.0	13.4	13.4	[2]
PA-2	13.4	12.8	12.7	15.0	15.4	14.1	13.5	13.2	15.1	14.3	14.2	14.6	16.3	16.1	15.0									
AG-TOU	11.3	10.3	10.8	13.2	13.8	11.9	11.0	10.5	11.8	11.0	10.7	11.1	12.0	11.1	9.8	12.5	13.6	12.5	10.4	11.0	12.0	16.3	11.4	[3]
TOU-PA-5	10.5	9.4	10.2	12.3	12.9	11.0	10.1	9.7	11.1	10.4	9.8	10.1	11.0	11.1	9.6									
Ag. and Pumping	13.6	12.8	12.7	14.9	15.1	13.2	12.2	11.8	13.4	12.5	11.9	12.3	13.3	12.5	11.3	12.6	14.2	13.4	11.9	12.6	12.5	12.2	12.1	
St. and Area Lighting	26.1	21.2	20.2	22.2	23.6	20.7	19.0	17.3	18.1	19.4	19.8	20.9	21.0	20.3	19.1	19.0	19.2	19.5	18.0	17.9	17.4	17.5	15.9	
STANDBY/SEC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	11.7	13.1	13.6	11.7	12.2	12.0	8.8	12.3	
STANDBY/PRI	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	12.4	12.8	13.2	11.1	11.9	11.7	11.4	12.4	
STANDBY/SUB	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	8.3	9.6	9.7	5.9	7.6	7.5	7.8	8.0	
Standby	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	9.4	10.4	10.7	7.3	8.7	8.4	8.4	9.1	
Total System	14.8	14.9	14.6	17.5	19.2	17.2	15.7	15.3	17.2	16.0	15.3	15.6	15.8	15.3	14.8	15.6	16.1	15.9	14.4	14.9	14.8	14.3	14.7	
CPI Deflator (LA Area) Base Year: 2016	1.54	1.50	1.45	1.41	1.37	1.33	1.29	1.23	1.18	1.15	1.11	1.12	1.10	1.07	1.05	1.04	1.03	1.02	1.00	0.97	0.94	0.91	0.88	[4]

[1] Forecasts calculated from Present Rate Revenues ("PRR") from 2020 ERRA Application (Nov 2019 Update). Excludes PUCRF Revenues.
[2] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands < 200 kW (PA-1 and PA-2 mapped to TOU-PA-2)
[3] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands ≥ 200 kW (AG-TOU and TOU-PA-5 mapped to TOU-PA-3)
[4] Estimated figure

Note: During the Enery Crisis of 2001-2002, the Commission adopted a 3 ¢/kWh surcharge. The majority of the impact of this increase went to Large Power and Commercial customers. SCE, over time, is driving towards getting each group to pay its cost to service.

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Table 3

Historical Average Rates by Rate Group (Nominal ¢/kWh) Based on Recorded Revenue and Sales
2019 Average Rates by Rate Group Based on Forecasted Revenue and Sales

Bundled Service

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	[1]
Domestic	118%	115%	114%	104%	96%	99%	103%	104%	108%	109%	109%	109%	108%	110%	113%	111%	104%	106%	112%	110%	112%	114%	117%	
TOU-GS-1	125%	122%	120%	130%	125%	122%	121%	123%	121%	126%	123%	120%	122%	122%	125%	117%	116%	115%	110%	109%	109%	109%	107%	
TC-1	76%	74%	74%	83%	96%	96%	99%	93%	92%	96%	100%	103%	110%	112%	111%	113%	118%	122%	124%	118%	119%	118%	111%	
TOU-GS-2	103%	103%	100%	106%	110%	109%	109%	109%	107%	103%	104%	106%	110%	108%	106%	108%	111%	111%	110%	110%	109%	108%	106%	
TOU-GS-3	100%	90%	102%	105%	105%	100%	97%	87%	94%	102%	102%	102%	95%	93%	91%	96%	101%	101%	98%	98%	98%	96%	95%	
Sm. and Medium Comm.	107%	106%	104%	110%	113%	111%	111%	110%	107%	107%	107%	107%	108%	107%	106%	107%	110%	109%	107%	107%	106%	105%	103%	
TOU-8-Sec	84%	83%	87%	98%	102%	98%	92%	92%	90%	90%	90%	91%	91%	89%	87%	91%	95%	95%	88%	89%	89%	89%	85%	
TOU-8-Pri	75%	74%	79%	87%	92%	89%	84%	86%	86%	85%	86%	83%	82%	81%	77%	81%	84%	84%	77%	78%	79%	78%	77%	
TOU-8-Sub	51%	52%	56%	67%	67%	65%	61%	61%	62%	60%	59%	56%	56%	54%	50%	54%	58%	58%	45%	52%	52%	53%	55%	
Large Power	70%	72%	77%	85%	90%	87%	82%	81%	81%	79%	79%	78%	77%	75%	72%	78%	82%	82%	73%	76%	76%	76%	75%	
PA-1	133%	122%	120%	115%	109%	115%	115%	122%	125%	121%	127%	127%	135%	138%	131%	82%	92%	88%	90%	93%	92%	94%	94%	[2]
PA-2	90%	86%	87%	86%	80%	82%	86%	86%	88%	89%	93%	93%	103%	105%	101%									
AG-TOU	76%	69%	74%	75%	72%	69%	70%	69%	69%	69%	70%	71%	76%	73%	66%	80%	84%	78%	72%	74%	112%	114%	79%	[3]
TOU-PA-5	71%	63%	70%	70%	67%	64%	64%	63%	65%	65%	64%	65%	69%	73%	65%									
Ag. and Pumping	92%	85%	87%	85%	79%	76%	77%	77%	78%	78%	78%	79%	84%	82%	77%	81%	88%	84%	83%	84%	84%	85%	83%	
St. and Area Lighting	176%	142%	138%	127%	123%	120%	121%	114%	105%	121%	130%	134%	132%	133%	129%	122%	119%	122%	125%	120%	118%	122%	108%	
STANDBY/SEC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	75%	81%	85%	81%	81%	81%	61%	84%	
STANDBY/PRI	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	79%	80%	83%	77%	80%	79%	80%	84%	
STANDBY/SUB	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	53%	59%	61%	41%	51%	50%	54%	55%	
Standby	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	60%	65%	67%	51%	58%	57%	59%	62%	
Total System	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	

[1] Forecasts calculated from Present Rate Revenues ("PRR") from 2020 ERRA Application (Nov 2019 Update). Excludes PUCRF Revenues.
[2] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands < 200 kW (PA-1 and PA-2 mapped to TOU-PA-2)
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Note: During the Enery Crisis of 2001-2002, the Commission adopted a 3 ¢/kWh surcharge. The majority of the impact of this increase went to Large Power and Commercial customers. SCE, over time, is driving towards getting each group to pay its cost to service.

3. Management Control of Rate Components

SCE requests in CPUC and FERC General Rate Cases[4] funding to operate its generation, transmission and distribution operations in order to provide safe, reliable, affordable and clean electric service to all customers in its service territory. Based on the funding authorized by the Commission, SCE has the ability to manage those core utility operations. However, funding is not always adequate to fulfill all infrastructure replacement requirements on the company's planned schedule or to meet emergent operational needs. For example, in the short-term SCE will be seeking additional funding above both authorized CPUC and FERC General Rate Case levels to respond to what is the new normal of increased wildfire risk in Southern California.

Another portion of SCE's total revenue requirement is associated with its power procurement function. Based on a set of assumptions that reflect regulatory and legislative requirements, SCE requests funding to procure enough power to meet its customers' load. Although there are procurement cost components that are driven by market forces outside of SCE's control, such as natural gas prices, SCE has been given some authority by the CPUC to use hedging tools to reduce the variability in cost of power to its customers.

A third category of costs are associated with policies driven by the Commission and Legislature for funding programs such as Demand Response, Energy Efficiency, Solar Initiatives, Self-Generation, Transportation Electrification and Low-Income programs. Consistent with these policies, SCE makes initial requests for funding these programs, but the final authorized funding amounts are determined by the

[4] SCE's FERC transmission revenue requirement is currently established through a formula rate mechanism.

Commission based on policy objectives. Finally, there are costs included in the total revenue requirement that are fully outside of SCE's management control such as DWR Power and Bond Charge revenue requirements and other costs whose magnitude are prescribed by the legislature or a regulatory agency (e.g., while the requirement in Assembly Bill (AB) 1890 to collect revenue for the California Energy Commission to fund its Renewable, and Research, Development and Demonstration (RD&D) programs expired at the end of 2011, the CPUC issued a decision that continues funding for RD&D programs through 2020).

SCE relies on a policy of marginal cost-based allocation in order to control the level of costs allocated to the various customer classes. This policy helps to limit the burden of any costs on a given customer class and helps to direct a larger allocation of those costs to customer classes who are driving the marginal expenditures. In other circumstances, the allocation of costs may be governed by statute or Commission order.

SCE is committed to fulfilling its core mission of providing safe, reliable, affordable and clean electricity to its customers through operational and service excellence across all business and functional areas.

4. Utility's Policies and Recommendations for Limiting Costs and Rate Increases While Meeting the State's Energy and Environment Goals for Reducing Greenhouse Gases

Wildfire risk in SCE's territory has increased dramatically in recent years due to climate change, drought, and other factors such as a growing wildland-urban interface and the significant build-up of fuel, including on federal and state forest lands. By the summer of 2018, SCE recognized that wildfire risk had increased to the point where the

safety of its communities required additional and immediate measures to address this new higher level of wildfire risk. Accordingly, SCE filed its Grid Safety and Resiliency Program (GSRP) Application (A.18-09-002) in September 2018, proposing new grid hardening measures, such as SCE's Wildfire Covered Conductor Program (WCCP), enhanced situational awareness activities, such as additional cameras, weather stations, and modeling tools, and enhanced operational practices for the September 2018-December 2020 period (*i.e.,* SCE's GSRP was designed to provide funding and authority for critical wildfire mitigation activities prior to the implementation of SCE's 2021 GRC).

Shortly after SCE filed its GSRP Application, former Governor Brown signed Senate Bill (SB) 901, which sets in motion wide-ranging activities to strengthen California's ability to prevent and recover from catastrophic wildfires. SB 901 requires, among other things, electric utilities to prepare and submit annual wildfire mitigation plans (WMPs) that describe the utilities' plans to prevent, combat, and respond to wildfires. In recognition that the utilities' currently-authorized or pending GRCs (and other relevant proceedings, such as SCE's GSRP) may not have contemplated the level of wildfire mitigation activity that is now needed, SB 901 also authorized the creation of memorandum accounts to track wildfire mitigation-related incremental costs. SCE filed its 2019 Wildfire Mitigation Plan (WMP) in February 2019 outlining its mitigation strategies, which included increased vegetation management activities in high fire risk areas (HFRA), activities from SCE's GSRP, as well as additional new measures such as SCE's Enhanced Overhead Inspection initiative. Because the vast majority of the activities proposed in SCE's 2019 WMP are incremental to activities proposed and

authorized in SCE's 2018 GRC, most of the costs of executing the 2019 WMP were not reflected in customers' 2019 rates and were thus recorded to memorandum accounts for later recovery.

SCE filed its 2021 GRC in August 2019, forecasting approximately $2.8 billion in O&M and $5.0 billion in capital expenditures for its 2021 test year. Although the 2021 GRC request provides funding for the wildfire mitigation activities that will be performed in 2021-2023, SCE submits that it does not currently have cost recovery for the critical work that is being performed today, in 2019 and 2020. Accordingly, and pursuant to the November 25, 2019 2021 GRC Scoping Memo, SCE will submit testimony in a "Track 2" of its 2021 GRC on February 20, 2020, requesting review and recovery of its recorded 2018-2019 wildfire mitigation costs, and in a "Track 3" of its 2021 GRC in February 2021, requesting review and recovery of its recorded 2020 wildfire mitigation costs.[5]

SCE acknowledges that the increase requested in the 2021 GRC, coupled with SCE's GSRP Application and its upcoming Track 2 and 3 2021 GRC requests, will result in a material impact on customer rates. SCE believes that it has struck the proper balance between seeking authorization for time-sensitive public safety measures and doing what it can to reprioritize or scale back other initiatives that will be deferred to future GRCs. Catastrophic wildfire risk is an existential problem facing the citizens of California, albeit one that cannot unilaterally be solved by SCE or the utilities at large. SCE must take all actions within its reasonable control to reduce wildfire risks to its communities. That

[5] Track 2 of SCE's 2021 GRC will not seek recovery of GSRP costs. SCE and parties to A.18-09-002 submitted a settlement agreement in July 2019 that authorizes a certain level of activity for the 2018-2020 period. Additionally, the settlement agreement allows SCE to track 2018-2020 GSRP costs above those authorized in the settlement agreement for review and recovery in Track 3 of SCE's 2021 GRC, which will be submitted in February 2021.

solemn responsibility is the largest driver of upcoming rate increases. Importantly, if SCE does not pursue this vital risk mitigation, and future wildfires continue to increase, customers will be exposed to greater health and safety risks as well as future electricity costs that would likely be greater than those associated with SCE's proposals.

While the California wildfire threat is currently SCE's primary operational focus, California is also continuing its leadership in addressing climate change and air pollution. The state's approved greenhouse gas (GHG) reduction goals call for a 40 percent reduction in GHG emissions from 1990 levels by 2030 and a new and ambitious target to reach carbon neutrality by 2045. Air quality goals include a 90 percent reduction in emissions of nitrogen oxides from 2010 levels in some of the state's most polluted areas by 2032. Meeting environmental goals of this magnitude will require fundamental changes to infrastructure and transportation and, at the same time, can also help the California economy by creating new jobs. SCE supports these environmental goals and in November of 2019, published its Pathway 2045, which is an integrated approach to reduce GHG emissions and air pollution that builds upon SCE's 2017 Clean Power and Electrification Pathway analysis. Both papers find that focused, economy-wide efforts are needed to reduce GHG emissions across all sectors with immediate and sustaining action needed primarily in the transportation, electric power, and building sectors in California. Pathway 2045 builds on existing state policies and uses a combination of measures to produce the most cost-effective and feasible path forward among the options studied.

Reaching California's 2030 GHG reduction goals under the Clean Power & Electrification Pathway will require:

- An electric grid supplied by 80 percent carbon-free energy;

- More than 7 million electric vehicles on California roads; and
- Using electricity to power nearly one-third of space and water heaters, in increasingly energy-efficient buildings.

Reaching the 2045 carbon neutrality goals pursuant to Pathway 2045 will require:

- Powering 100% of retail electricity sales using GHG-free resources
- Electrifying 75% of vehicles
- Electrifying 70% of buildings
- Using significant amounts of low-carbon fuels such as green hydrogen and biomethane for non-electric energy
- Capturing, sequestering, and/or using the remaining carbon emissions

California's policy goals cannot be achieved by the electric sector alone, which is already at the forefront of California's fight against climate change and today accounts for only 19 percent of the state's GHG emissions. Moreover, the electric sector continues to deal with industrywide changes that may compromise its ability to influence climate change policies. As more and more customers in the utility's service territory have their generation procured by alternate service providers (*e.g.*, Community Choice Aggregators (CCAs) or Electric Service Providers (ESPs)), the determination of Power Charge Indifference Adjustment (PCIA) rates becomes increasingly important to prevent statutorily-prohibited cost-shifting to remaining bundled customers. In 2020, PCIA rate capping will begin, whereby remaining bundled customers will be required to "finance"

any undercollection from departing load customers that results from the PCIA rate capping. A trigger mechanism is in place to help limit the magnitude of this undercollection and its impact on bundled customers' rates. The transportation sector (including fuel refining) and fossil fuels used in space and water heating now produce almost three times as many GHG emissions as the electric sector and more than 80 percent of the air pollution in California. Further, through electrification of large portions of the energy and building sectors, SCE's Pathway 2045 shows that California customers' total energy expenditures (i.e., combined expenditures of electricity and other energy usage) could see reductions over time. Specifically, while electrification may increase electricity bills, electrification also has downward pressure on electric rates. Additionally, electrified transportation and building space and water heating is significantly more efficient than incumbent fossil fuel technologies and avoids large customer expenditures on gasoline and natural gas. As California adopts integrated solutions to decarbonize the economy, it becomes increasingly important to not only focus on electricity rates and costs, but to also consider the total customer expenditures on energy.

Accomplishing these tasks, just as was the case with achieving the goals of California's landmark carbon reduction bills Assembly Bill (AB) 32 and Senate Bill (SB) 32, will require careful thought, broad market solutions, and flexibility so as to avoid undue cost implications and to continue California's role as a model for others to follow in responsible GHG reductions.

California's environmental policies need to be coordinated to be effective. Simultaneously pursuing GHG reduction, local air emissions reductions, water use

restrictions, and land use restrictions requires a comprehensive and coordinated process. Otherwise, resources might be wasted, and the reliability and affordability of electricity may be affected.

Some of the key actions that the CPUC, Legislature, and Governor can take to help manage and minimize rate increases in the future are described below. These generally fall into the categories of finding least cost feasible solutions to meeting GHG reduction goals, maintaining fair and efficient rate structures for customers, and effectively adapting to changing technologies, particularly those impacting the distribution grid, as advances in this space are potentially rapidly transforming how customer needs will be met in the future.

In the area of renewable procurement, providing flexibility to use least cost options is critical to ensuring the clean power used to serve future customer needs is affordable. This means (a) limiting the technology based targets and restrictions sometimes used to satisfy the needs of subsets of the renewable community, (b) appropriately expanding the geographic scope of new renewable development to incorporate out of state projects that help meet California's energy needs while displacing higher emitting out of state resources in the process, (c) recognizing that many new renewable resources are connecting on the distribution grid that needs to be modernized, and (d) achieving renewable expansion goals at least cost by relying on markets without artificial distinctions such as the interconnection points to determine the mix of future renewable development.

Another critical factor in achieving GHG reduction policies in the State without an undue cost burden on customers is the transition away from substantial

transfers of costs in rates between customer groups. For example, the current Net Energy Metering (NEM) tariff continues to result in substantial shifting of costs to non-participating customers, who are paying for the grid being used by net energy metering customers. As of December 31, 2019, the estimated annual residential NEM cost shift increased $51 million over the previous year of $516 million, surpassing the total annual subsidy for qualifying customers under the CARE program, which has a statutorily prescribed level of subsidy to customers. SCE supports continued sustainable growth of distributed solar, driven by market conditions and appropriate policies –including equitable electricity pricing structures.

An inequity that deserves more of the Commission's attention is the rate impact and cost shift that occurs when memorandum accounts (typically established in applications involving spend prior to authorized cost recovery) are established to record costs related to a proceeding that is subject to significant delays in Commission approval. Therefore, the costs incurred in prior periods are borne by future customers, which, in the case of ongoing wildfire-related work, could result in a compounding of rate increases in out years. Additionally, in many cases, if the delays occur over a period of years, customers may have moved in and out of SCE's territory and it is understandably unfair for current customers to pay for costs from prior periods.

As more and more new resources seek to connect to the distribution grid and want to provide and be compensated for services, a modernized grid that can monitor and control the two-way flow of power in the distribution system will be critical to maintaining, and hopefully enhancing, the reliability and resiliency of the grid. To prepare for this changing environment where GHG abating technologies such as

photovoltaic generation, energy storage, demand side management, and transportation electrification play an increasing role in meeting future customer needs, California must have the electrical infrastructure capable of meeting these needs. The CPUC, Legislature, and Governor's office must have consistent policies related to the expanding role of distributed energy resources as well as expanding distribution infrastructure capability to integrate these resources.

Finally, utilities must be vigilant in finding least cost paths to meet current and future customer needs. Maintaining its focus on operational excellence is one of the means employed by SCE to control its budgets and revenue requirements. Operational excellence is the framework SCE management has established to deliver on our mission of providing safe, reliable, and affordable power for our customers. Operational excellence builds off our core value – Continuous Improvement. SCE has rededicated itself to exploring every opportunity to improve the operations across the company and taking action to implement appropriate improvements.

APPENDIX A

1. Revenue Requirements Effective January 1, 2019

a. Summary of Revenue Requirements by Rate Component/Key Category

The table below shows SCE's Total System Revenue Requirements and Bundled System Average Rate for Bundled Service customers by key category as of January 1, 2020, with a comparison to the same period prior.

	January 1, 2019			January 1, 2020				
SCE	Total System Revenue ($millions)	Percent	Rate	Total System Revenue ($millions)	Percent	Rate	Bundled Residential Revenue ($millions)	Percent
Generation	5,346	45.0%	7.5	5,302	46.2%	8.5	2,007	51.1%
New System Generation	398	3.4%	0.5	444	3.9%	0.6	146	3.7%
Distribution (Includes GHG Allowance Return)	4,318	36.3%	5.6	4,064	35.4%	5.2	1,244	31.7%
Public Purpose Programs	475	4.0%	0.6	294	2.6%	0.4	123	3.1%
Nuclear Decommissioning	4	0.0%	0.0	4	0.0%	0.0	1	0.0%
Transmission	962	8.1%	1.2	949	8.3%	1.2	316	8.0%
DWR Bond Charge	377	3.2%	0.5	428	3.7%	0.5	92	2.3%
TOTAL	11,880	100.0%	15.9	11,484	100.0%	16.4	3,930	100.0%

* No change by rate component is greater than 10% year over year

b. Summary of Revenue Requirements by Proceeding

The table below shows SCE's Total System Revenue Requirements by proceeding as authorized by the Commission and FERC effective as of January 1, 2020, including the sources of the data.

Southern California Edison Company
January 1, 2020 Consolidated Revenue Requirements In Rate Levels By Proceeding
TOTAL SYSTEM
($000)

	Column 1	Column 2	Column 3	Column 4
	Revenue Requirement Component	Revenue Rqmts January 1, 2020 Rate Levels	Percent of Total Revenue Requirements	Authority For Change
1.	**ERRA FORECAST PROCEEDING**	**4,867,996**	**42.4%**	D.19-02-024, Advice 3972-E-A
2.	**GRC PROCEEDING**			
3.	Base Revenue Requirement	5,859,714	51.0%	D.19-05-020, Advice 4103-E
4.	GRC-related balancing/memo accounts and refunds	(701,663)	-6.1%	D.15-11-021, D.19-05-020
5.	SUBTOTAL	**5,158,051**	**44.9%**	
6.	BRRBA, NDAM, CARE, PPPAM	(239,181)	-2.1%	D.15-10-037
7.	2018 GRC - FF&U impact on non-GRC items	(1,007)	0.0%	D.19-05-020
8.	Aliso Canyon Energy Storage	11,925	0.1%	D.18-06-009, Advice 4091-E
9.	Low Income Programs (ESAP & CARE)	72,461	0.6%	D.16-11-022, Resolution E-4885. Advice 3824-E-A
10.	Statewide ME&O	8,753	0.1%	D.16-09-020, Advice 3869-E
11.	Charge Ready Phase 1 Pilot	7,247	0.1%	D.16-01-023, D.18-12-006, Advice 4092-E
12.	Transportation Electrification	6,796	0.1%	D.18-01-024, D.18-05-040, Advice 4092-E
13.	Demand Response Programs	38,438	0.3%	D.17-12-003, D.18-05-041
14.	EPIC - RD&D and Renewables	76,978	0.7%	D.18-01-008
15.	Energy Efficiency	93,970	0.8%	D.18-05-041
16.	SJV Disadvantaged Communities Pilot Balancing Account	10,248	0.1%	D.18-12-015 Advice 3946-E-B
17.	FERC Base Transmission	962,976	8.4%	FERC Docket No. ER19-1553
18.	FERC Transmission Balancing Accounts	(13,881)	-0.1%	Docket No. ER20-268 and ER20-248
19.	SUBTOTAL	**1,035,724**	**9.0%**	
20.	**DWR**	**422,669**	**3.7%**	D.19-12-007
21.	**TOTAL REVENUE REQUIREMENT**	**11,484,439**	**100.0%**	

c. Description of Rate Components and Revenue Requirements

SCE recovers its revenue requirements through the following retail rate components: Generation, Cost Responsibility Surcharge (CRS), New System

Generation, Distribution, Public Purpose Programs, Nuclear Decommissioning and Federal Energy Regulatory Commission (FERC) jurisdictional Transmission. In addition, SCE is authorized to include on customer bills the DWR Power Charge and Bond Charge on behalf of the California Department of Water Resources (DWR).

a. **Generation** – Through the Generation rate component, SCE recovers the costs of its generation portfolio which include the cost of SCE's Utility Owned Generation (UOG) consisting of the fuel, base O&M and capital-related revenue requirements associated with its nuclear, gas, and hydro plants. In addition, SCE recovers all of its purchased power costs required to meet its load not met by its UOG.[6] The purchased power costs include the costs of Qualifying Facilities (QFs), and all other bilateral contracts that SCE has entered into since 2003 when the company was authorized to resume the power procurement function and make purchases and sales through the wholesale markets. The impact of renewable contracts entered into to meet the Renewables Portfolio Standard and Greenhouse Gas costs will be reflected in generation rates.

b. **Cost Responsibility Surcharge** – Through the CRS, which includes the Competition Transition Charge (CTC), DWR Bond Charge and PCIA rate components, SCE recovers from departing load customers (*e.g.*, customers who have their generation procured by an alternate service provider some as a CCA or ESP) the above-market costs of the SCE generation portfolio that was procured prior to their departure. The revenue

[6] By the end of 2011, all of the DWR purchased power contracts that were allocated to SCE's bundled service customers expired. Therefore, beginning in 2012, SCE is supplying 100% of its bundled service customers' generation requirements.

generated from the CRS reduces the generation costs that must be collected from SCE's bundled service customers so that they remain indifferent to the departure of those customers, and are not burdened with paying for the above-market costs of the procurement SCE had planned and incurred to serve the departing load customers. As noted above, starting in 2020, the PCIA portion of the CRS is capped for certain vintages, which thus transfers costs (in theory, only temporarily) to the remaining bundled service customers who must finance this undercollection. A PCIA trigger was also adopted to limit the magnitude of the undercollection related to capped PCIA rates.

c. **New System Generation** – Through the New System Generation (NSG) rate component, SCE recovers the costs of those "new generation" assets that the Commission has required SCE to procure in order to maintain system reliability for the benefit of all customers. The NSG revenue requirement includes the contracted procurement costs less the value of the energy produced. The net cost, or capacity cost, is recovered from all customers who benefit from the additional system capacity provided by the new generation, including DA and Community Choice Aggregation (CCA) customers.

d. **Distribution** – Through the Distribution rate component, SCE primarily recovers its base distribution O&M costs and its capital-related revenue requirement. In addition, the Commission has authorized SCE to recover its Charge Ready Program funding, Demand Response program funding, California Solar Initiative program funding, and some Energy Efficiency incentives through the Distribution rate component. The Commission has authorized SCE to provide the California Alternate Rate for Energy (CARE) discount to the income-qualified customers through the Distribution rate

component. As a result of the Commission's decision in the GHG Revenue Rulemaking (R.11-03-012) and the Residential Rate R.12-06-013, SCE returns proceeds that result from the cap-and-trade market to residential customers through a semi-annual Climate Credit (i.e. a credit included on customer's bills) and through the distribution rate component to certain small business customers.[7]

e. **Public Purpose Programs Charge (PPPC)** – Prior to 2012, SCE recovered the legislatively mandated Public Goods Charge funding for the California Energy Commission administered Research Development and Demonstration and Renewable programs, Self-Generation Incentive Program funding, plus a portion of the SCE-administered Energy Efficiency programs, through the PPPC. The funding for these three programs expired on December 31, 2011 as mandated by P.U Code 399. The Commission issued a decision in December 2011 that continued this funding in 2012 through 2020 using the name Electric Program Investment Charge. In addition, through the PPPC rate component SCE recovers additional program funding authorized by the Commission for Procurement Energy Efficiency, and Low-Income programs. The Commission has authorized SCE to recover the costs of the CARE program including the discount provided to CARE-eligible customers from all non-CARE customers through the PPPC.

f. **Nuclear Decommissioning** – Through the Nuclear Decommissioning rate component, SCE recovers the customers' portion of the Nuclear Decommission Trust

[7] Proceeds are also returned to certain large customers defined as Energy-Intensive Trade-Exposed through an annual bill credit or check.

funding authorized by the Commission to be used to decommission SCE's share of the San Onofre and Palo Verde Nuclear Generating Stations. In addition, SCE recovers costs associated with the storage of spent nuclear fuel through this rate component.

g. **FERC-Jurisdictional Transmission** – SCE's FERC-jurisdictional transmission rate is comprised of four components: 1) Base Transmission which recovers the O&M and capital-related revenue requirement associated with transmission assets under ISO operational control and subject to FERC's jurisdiction; 2) flow-through to customers of transmission revenues generated through wholesale customers' use of the transmission system; 3) Reliability Services costs related to contracts signed by the California Independent System Operator (CAISO) with certain generators needed to maintain system reliability; and 4) Transmission Access Charge which reflects the net contribution by SCE's customers to the transmission revenue requirements of all participating transmission owners in the CAISO system.

As SCE moves forward to meet the State's renewable goals, it must construct new transmission lines to bring the renewable generation from out-lying areas to the load centers. The construction of additional transmission facilities will increase SCE's FERC-jurisdictional Transmission rates.

h. **DWR Power Charge and Bond Charge** – In early 2001, as the result of the energy crisis and AB1X, DWR entered into long term power contracts that were necessary to meet the state's Investor Owned Utilities' (IOUs') net short requirements. The Commission authorized SCE to recover on behalf of DWR, the revenue requirement associated with these contracts through the DWR Power Charge. As mentioned above,

all of the remaining DWR contracts that had been allocated to SCE's bundled service customers expired as of December 31, 2011. In addition, in order to recover the costs DWR incurred in early 2001 to purchase energy on behalf of IOUs' customers from dysfunctional wholesale markets which were initially financed by the State's General Fund, the Commission authorized SCE to bill the DWR Bond Charge. All of the revenues associated with the DWR Power and Bond Charges are collected by SCE and passed on to DWR.

Since 2001, DWR was required to maintain high levels of operating reserves such that DWR would have enough cash on hand to fulfill its contractual obligations in case power prices skyrocketed. Since the power contracts have expired, DWR no longer is required to maintain this level of reserves and has returned them to customers. Therefore, the Commission-allocated DWR Power Charge Revenue Requirement to SCE's bundled service customers in 2019 is minimal.

In 2019, the DWR Bond Charge was increased from the 2018 level (approximate increase of $56 million for SCE customers), which will complete the repayments for the Energy Crisis bonds as the charge will transition into a Wildfire Fund Nonbypassable charge later in 2020. The final month in which the DWR Bond Charge will be collected is unknown at this time, but it may be as early as the second half of 2020. Pursuant to statute, the annual Wildfire Fund revenue requirement shall be equal to the average annual amount of collections by DWR with respect to the DWR Bond Charges imposed for the period from January 1, 2013 through December 31, 2018.

2. Sales Forecast

a. Provide your utility's publicly available authorized load / sales forecast data effective January 1, 2020. Please provide the source of this data.

SCE received approval of its 2020 ERRA Forecast application (A.19-06-002), on January 16, 2020, too late for a January 1 implementation, which also approves the 2020 sales forecast. Therefore, implementation of the 2020 authorized sales is expected to occur in April 2020 along with other related authorized revenue updates. The total sales forecast for 2020 is shown below, as provided in the 2020 ERRA Forecast application with comparisons to prior years (2018 is recorded while 2019 and 2020 are forecast).

Annual Retail Sales by Customer Class
(GWh)

	2018	2019*	2020*
1. Residential	29,865	28,771	28,633
2. Commercial	42,369	41,484	41,954
3. Industrial	6,786	6,163	5,759
4. Other**	6,255	5,966	5,877
5. Total Retail Sales	85,276	82,383	82,223

*Forecast
**Includes Public Authorities, Agriculture, and Street Lighting Sales

b. Provide your utility's publicly available actual load / recorded sales data for calendar year 2019. Please provide the source of this data.

Recorded at meter sales for 2019 was 82,934 GWh and the source is SCE's internal billing system, however this will be made public in SCE/EIX's 2019 Annual Report (SEC 10-K filing)

3. Energy Burden

a. Provide annual 2019 energy burden data by baseline territory and service territory for Non-CARE, CARE, and all bundled residential customers using 2019 recorded average usage data.

The household income data used in the table below was provided by Acxiom which estimated income according to a proprietary algorithm for SCE's individual service accounts. Where income is missing, it is filled in by the average known incomes of the same ZIP code. Income level is also capped at $125,000.

The individual service accounts are attached to locations which have an assigned baseline zone in SCE's Customer Service System.

Is CARE?	Zone 05	06	08	09	10	13	14	15	16	Grand Total
CARE										
Percent of Total Customers	0.0%	2.1%	5.0%	3.1%	6.0%	1.6%	2.5%	0.6%	0.3%	21.3%
Average Monthly kWh	603	345	379	443	549	607	565	671	513	483
Average Monthly Bill	$69	$42	$47	$54	$68	$76	$64	$82	$66	$59
Average Monthly Income	$6,980	$4,382	$3,859	$4,279	$4,141	$3,178	$3,650	$3,614	$4,011	$3,972
Average Energy Burden	1.3%	1.8%	2.1%	2.1%	2.9%	4.2%	3.0%	4.3%	2.4%	2.7%
Average rate	11.4	12.3	12.4	12.2	12.4	12.6	11.3	12.2	12.9	12.2
Non-CARE										
Percent of Total Customers	0.0%	11.9%	14.8%	8.5%	13.2%	2.0%	4.0%	2.0%	1.7%	58.2%
Average Monthly kWh	608	438	480	553	633	696	610	767	480	543
Average Monthly Bill	$104	$81	$87	$96	$108	$119	$99	$133	$88	$95
Average Monthly Income	$7,945	$6,812	$6,183	$6,250	$5,824	$4,637	$4,522	$5,817	$5,086	$6,028
Average Energy Burden	1.6%	1.6%	2.0%	2.1%	2.8%	4.1%	3.4%	3.5%	2.1%	2.6%
Average rate	17.1	18.5	18.1	17.5	17.0	17.1	16.2	17.3	18.2	17.6
Total Percent of Total Customers	**0.0%**	**14.1%**	**19.8%**	**11.6%**	**19.3%**	**3.6%**	**6.5%**	**2.7%**	**2.0%**	**79.5%**
Total Average Monthly kWh	**608**	**423**	**455**	**523**	**607**	**657**	**592**	**744**	**486**	**527**
Total Average Monthly Bill	**$102**	**$75**	**$77**	**$85**	**$95**	**$100**	**$85**	**$120**	**$84**	**$86**
Total Average Monthly Income	**$7,888**	**$6,443**	**$5,593**	**$5,727**	**$5,298**	**$3,997**	**$4,183**	**$5,289**	**$4,918**	**$5,477**
Total Average Energy Burden	**1.4%**	**1.7%**	**2.1%**	**2.1%**	**2.8%**	**4.2%**	**3.2%**	**3.9%**	**2.3%**	**2.6%**
Total Average rate	**16.7**	**17.7**	**16.9**	**16.3**	**15.7**	**15.2**	**14.3**	**16.2**	**17.4**	**16.3**

Monthly historical bills for individual service accounts in statistical year 2019,
include bills for days in December 2018 and exclude days in December 2019 depending on billing cycles
Master meter accounts are excluded
Bill amounts exclude taxes
Climate Credit is incorporated in historical bills
Income data provided by Acxiom, estimated by its proprietary algorithm at SCE service account level
Where income data is missing, average income for the ZIP code is used
Income capped at $125,000
Energy burden shown is average of individual energy burdens, not the average bill divided by the average income

4. Outlook from May 1, 2020 to April 30, 2021

The table below shows anticipated rate changes associated with pending (or to-be-filed) applications. Dates that are listed under the "Requested/Expected Implementation Date" column heading indicate effective dates of anticipated rate changes.

Additionally, SCE will implement a consolidated rate change in April 2020 to implement decisions approving SCE's 2020 ERRA Forecast and Cost of Capital Applications and update for 2019 year-end balances in its revenue-related balancing accounts. SCE currently forecasts the April 2020 rate change revenue increase to be approximately $470 million. This amount is preliminary and will be updated in the consolidated rate change advice letter to be submitted in March 2020.

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Estimated/Requested Dollar Amount		Description	Impacted Rate Component
				2020 Revenue Requirement[1/]	2021 Revenue Requirement[1/]		
2021 GRC Track 1	A.19-08-013	August 2019	January 1, 2021	$5,859.7[2/]	$7,625.2	2021 base O&M and capital revenue requirement	Generation, Distribution, and New System Generation
Charge Ready Phase 2	A.18-06-015	June 2018	As soon as practicable	$57.8	$90.5	EVSE infrastructure and ME&O	Distribution
Grid Safety and Resiliency Program (GS&RP)	A.18-09-002	September 2018	As soon as practicable	$173.2[3/]	N/A (folded into 2021 GRC)	Wildfire risk mitigation measures	Distribution
Wildfire Expense Memorandum Account (WEMA)	A.19-07-020	July 2019	October 1, 2020	$505[4/]	N/A	Wildfire insurance premiums and financing costs for April 2018-June 2020 coverage	Distribution
Catastrophic Event Memorandum Account (CEMA)	A.19-07-021	July 2019	January 1, 2021	N/A	$88.4	2017 catastrophic event restoration costs and 2017-2018 drought-related bark beetle remediation	Distribution
Energy Savings Assistance Program	A.19-11-004	November 2019	January 1, 2021	$72.5[2/]	$69.6	Low Income Energy Efficiency (ESA) and CARE Administration funding for the 2021-2026 period	Public Purpose Programs

BPA/SCE Carbon Free Energy Product Pilot Transaction	A.19-10-001	October 2019	January 1, 2021	N/A	$1.0	Pilot program for energy efficiency-related carbon-free power	Public Purpose Programs
2021 ERRA Forecast	TBD	June 2020	January 1, 2021	$4,715.6[5/]	TBD	Recovery of estimated fuel and purchased power costs	Primarily Generation, some in New System Generation, Distribution, and Public Purpose Programs
2021 GRC Track 2	A.19-08-013	February 2020	January 1, 2021	TBD	TBD	2018-2019 vegetation management costs; 2019 wildfire mitigation costs that are currently being tracked in memorandum accounts	Distribution
FERC Formula Rate Change	N/A (Advice Letter)	November 2020	January 1, 2021	$963.0	TBD	Base Transmission Revenue	Transmission
FERC Transmission Balancing Accounts	N/A (Advice Letter)	May (TACBAA) and October (RSBA and TRBAA) 2020	June 1, 2020 and January 1, 2021	($13.9)		FERC-related balancing accounts	Transmission
DWR -- Power and Bond Charge/Wildfire Fund Charge	R.19-07-017	TBD	January 1, 2021	$428.1	$408.2	DWR Bond Charge: Recovers bonds procured by DWR during Energy Crisis; Wildfire Fund: Funds AB1054 Wildfire Fund	DWR Bond Charge/Wildfire Fund Charge
Wildfire Expense Memorandum Account (WEMA)	TBD	TBD	TBD	N/A	TBD	Wildfire insurance premiums and financing costs for July 2020-December 2020 coverage	Distribution
Catastrophic Event Memorandum Account (CEMA)	TBD	TBD	TBD	N/A	TBD	2018 – 2019 catastrophic event restoration costs	Distribution

1/ Represents revenue requirement at the end of each year (*i.e.*, revenue requirements that are scheduled to be implemented and fully amortized mid-year are shown in the year that it is first implemented into rates). For example, SCE proposes that the full WEMA revenue requirement be implemented October 1, 2019 and removed on September 30, 2020. As such, the WEMA revenue requirement is shown in 2019 and not shown in 2020.

2/ Authorized revenue requirement
3/ GS&RP 2018-20 revenue requirement based on settlement agreement filed July 2019. Does not reflect removal of AB 1054-related capital expenditures.
4/ SCE filed an interim motion for rate relief, requesting recovery of half of the requested amount beginning October 1, 2019. That motion is still pending before the Commission. SCE proposed that, if the Commission did not grant interim rate relief, the entire revenue requirement be recovered over 12 months beginning October 1, 2020 (and finishing September 30, 2021).
5/ Reflects 2020 ERRA Revenue Requirement approved in D.20-01-022. Final revenue requirement will be updated to reflect final balances in the various Fuel and Purchased Power Balancing Accounts.